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Comparison of West German and U.S. Flue Gas Desulfurization and Selective Catalytic Reduction Costs

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COMPARISON OF WEST GERMAN AND U.S. FLUE GAS DESULFURIZATION AND SELECTIVE CATALYTIC REDUCTION COSTS

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16. ABSTRACT The report documents a comparison of the actual cost of retrofitting flue gas desulfurization (FGD) and selective catalytic reduction (SCR) on Federal Republic of German (FRG) boilers to cost estimating procedures used in the U.S. to estimate the retrofit of these controls on U.S. boilers. (NOTE: By the end of the 1980s, more than 45,000 MWe and, by early 1990, more than 34,000 MWe of coal- and oil-fired utility boilers in the FRG will have been retrofitted with FGD and SCR, respectively.) The estimated capital costs of FGD using U.S. procedures compared well to the reported capital cost for the 13 FRG boilers evaluated. The difference between the estimated and actual costs was -8 to 12%. However, there are significant design differences between the U.S. systems, built to comply with New Source Performance Standards (NSPS), and the FRG systems. These differences, which result in significantly lower capital costs on a dollar per kilowatt basis for the FRG systems, include: no spare absorber modules, large scrubber modules, and smaller sorbent and waste handling systems due to the low sulfur coals burned in the FRG. The estimated capital cost of SCR using the U.S. procedures also compared well to the reported capital costs for the nine FRG boilers evaluated. The difference was between -5 and 16%.

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ABSTRACT

By the end of the 1980s, over 45,000 MWe and, by early 1990, over 34,000 MWe of coal- and oil-fired utility boilers in the Federal Republic of Germany (FRG) will have been retrofitted with flue gas desulfurization (FGD) and selective catalytic reduction (SCR), respectively. This report documents a comparison of the actual cost of retrofitting FGD and SCR on FRG boilers to cost estimating procedures used in the United States to estimate the retrofit of these controls on U.S. boilers. The estimated capital costs of FGD using the U.S. procedures compared well to the reported capital cost for the 13 FRG boilers evaluated. The percent difference between the estimated and actual costs was -8 to 12%. However, there are significant design differences between U.S. FGD systems built to comply with New Source Performance Standards (NSPS) and the FRG systems. These differences result in significantly lower capital costs on a dollar per kilowatt basis for the FRG systems versus the U.S. NSPS systems. These design differences include: no spare absorber modules, large scrubber modules, and smaller sorbent and waste handling systems due to the low sulfur coals burned in the FRG. The estimated capital cost of SCR using the U.S. procedures also compared well to the reported capital costs for the nine FRG boilers evaluated. The percent difference was between -5 and 16%. However, the U.S. procedures were modified to reflect the catalyst volume and cost used in the FRG boilers. The previous U.S. estimates used larger catalyst volumes and higher catalyst costs, and incorporated process contingences that were not used in this study to develop the SCR cost estimates.

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

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LIST OF ABBREVIATIONS AND SYMBOLS

ABBREVIATIONS

AFDC	--	allowance for funds during construction
BC	--	ballast coal
Btu	--	British thermal unit
DB	--	dry bottom
DM	--	deutsche marks (2 DM = $1.00 U.S.)
EPA	--	Environmental Protection Agency
EPRI	--	Electric Power Research Institute
ESP	--	electrostatic precipitator
FG	--	flue gas
FGD	--	flue gas desulfurization
FRG	--	Federal Republic of Germany (West Germany)
ft	--	feet
ft^3	--	cubic feet
HC	--	hard coal
HD	--	high dust
IAPCS	--	Integrated Air Pollution Control System
ID	--	induced draft
IPP	--	Institute for Industrial Production
kW	--	kilowatts (1 kW = 1 kJ/s)
kWe	--	kilowatt electric
L	--	lime
L	--	liter
L-FGD	--	lime-flue gas desulfurization
LG	--	lignite
L/LS	--	lime/limestone
LS	--	limestone
LSD	--	lime spray drying
LS-FGD	--	limestone-flue gas desulfurization
m	--	meter
m^3	--	cubic meter
mg/m^3	--	milligrams per cubic meter

LIST OF ABBREVIATIONS AND SYMBOLS
(Continued)

ABBREVIATIONS

MWe	--	megawatts electric
NA	--	not available
NAPAP	--	National Acid Precipitation Assessment Program
NATO	--	North Atlantic Treaty Organization
NSPS	--	New Source Performance Standards
ppm	--	parts per million
SCR	--	selective catalytic reduction
TG	--	tail gas
TPC	--	total process capital
TVA	--	Tennessee Valley Authority
WB	--	wet bottom

SYMBOLS

$Ca(OH)_2$	--	calcium hydroxide
NO_x	--	nitrogen oxides
SO_2	--	sulfur dioxide
SO_x	--	sulfur oxides

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SECTION 1

INTRODUCTION AND SUMMARY

In the mid-1980s, the Federal Republic of Germany (FRG) passed legislation requiring significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from existing large utility boilers. As a result, by 1988 over 45,000 MWe of conventional lime/limestone (L/LS) flue gas desulfurization (FGD) and lime spray drying (LSD) FGD systems have been installed, and by 1990 over 34,000 MWe of selective catalytic reduction (SCR) systems will have been installed. The reported capital costs for the L/LS- and LSD-FGD systems appear to be much lower than the actual costs of similar systems in the United States. The reported capital costs of the SCR systems are also much lower than the estimated cost of applying SCR systems to U.S. utility boilers.

This report documents the results of an analysis for comparing estimated versus actual capital costs for FGD and SCR systems installed at several utility boilers in the FRG. This analysis was conducted by Radian Corporation for the U.S. Environmental Protection Agency (EPA).

METHODOLOGY

The effort was conducted in two phases. In the first phase, site visits were conducted at five coal-fired utility boiler power plants in the FRG. Two of the plants (Walheim and Mannheim) were set up by the Institute for Industrial Production (IPP); two other plants (Niederaussem and Scholven) were visited as part of a North Atlantic Treaty Organization (NATO) committee meeting on the Control of Air Pollution from Coal Combustion, and the fifth plant (Ibbenbueren) visit was set up by Radian. Table 1 summarizes the boiler and coal characteristics for the five plants visited and evaluated under this study.

TABLE 1. GERMAN PLANT VISITS

Plant/Units	Fuel type[a]	Size (MWe)	Boiler type[b]	SCR type[c]	SCR on-line date	FGD type[d]	FGD on-line date
Walheim 1	HC	103	WB	--	--	LSD	1987
2	HC	153	WB	HD	1988	LSD	1987
Mannheim 3,4	HC	2x220	WB	TG	1988	LS	1988
7	HC	475	DB	HD	1988	LS	1988
Ibbenbueren B	HC	770	WB	TG	1988	L	1987
Niederaussem A-H	LG	9x300	DB	--	--	LS	1988
Scholven B	BC	370	DB	HD	1989	LS	1988
C	BC	370	DB	HD	1989	LS	1988
D	BC	370	DB	HD	1989	LS	1987
E	BC	370	DB	HD	1989	LS	1987
F	HC	740	DB	HD	1989	LS	1979-87
G,H	Oil	2x714	Oil	HD	1986-87	--	--

[a]Coal types: HC = hard coal, LG = lignite, BC = ballast coal.

[b]Boiler types: DB = dry bottom, WB = wet bottom.

[c]SCR types: HD = high dust, TG = tail gas.

[d]FGD types: LSD = lime spray drying, L = lime, LS = limestone.

Prior to the site visits, a questionnaire was sent to each utility company with the information needs of the study. This questionnaire provided the basis for the data gathering effort conducted during the plant visits. This data collection effort focused on obtaining capital cost information, general design and operating parameters, plot plans, and aerial photographs of the FGD and SCR systems.

In the second phase of the study, the collected information was used to develop cost estimates based on U.S. cost estimating procedures. The

procedures used were developed under a National Acidic Precipitation Assessment Program (NAPAP) project that estimated the cost and performance of SO_2 and NO_x controls at existing coal-fired utility boilers. The FGD procedures were based on the Electric Power Research Institute (EPRI) report "Retrofit FGD Cost-Estimating Guidelines" (1). The SCR cost estimating procedures were based on EPA and EPRI reports (2,3) and a Tennessee Valley Authority (TVA) report funded by the U.S. EPA (4). The capital cost estimates developed using the U.S. procedures were then compared to the reported costs for plants evaluated under this study. This comparison was conducted to identify capital cost differences, the reasons for the differences, and the changes needed to the cost estimating procedures.

SUMMARY OF FGD RESULTS

Table 2 summarizes the capital cost comparison for L/LS- and LSD-FGD for four of the plants. Capital cost estimates were not available for the individual boilers at the Scholven plant. The estimated capital costs for L/LS-FGD versus the reported actual costs were very close, having an absolute difference between -8 and 12%. Likewise, the average percent difference for the two LSD-FGD systems was 12%. The conversion rate used for this analysis was 2 deutsche marks (DM) to the U.S. dollar. The following changes were made to the FGD cost estimating model for this study.

Number of Spare Absorber Modules

None of the FGD systems evaluated in the FRG have spare absorber modules because German legislation allows the plant to be out of compliance for 240 hours a year. Therefore, the boiler does not have to shut down due to FGD system operation problems. In the United States, the 1979 New Source Performance Standard (NSPS) does not allow a boiler to operate out of compliance unless a spare absorber module is available. Additionally,

TABLE 2. SUMMARY OF FGD CAPITAL COST COMPARISON

Plant Name	Mannheim	Ibbenbueren	Niederaussem	Walheim
Boiler/Block	7	B	A-H	1-2
Coal sulfur	1.0	1.0	1.0	1.0
FGD type	LS-FGD	L-FGD	LS-FGD	LSD-FGD
FGD size (MWe)	475	770	2700	256
SO_2 removal efficiency (%)	80	85	90	90
Number of absorbers	1	2	9	2
Estimate of retrofit difficulty	1.10	1.10	1.87	1.16
Access/Congestion factor	Low	Low	Low	Low
Scope adder costs ($/kWe)	0	0	4.6	0
General facilities (%)	8	5	5	10
Total capital cost ($/kWe)				
Radian estimate	140	119	260	190
Actual reported[a]	140	130	240	170
Percent difference	0	-8	8	12

[a]Costs are based on an exchange rate of DM 2 to the U.S. Dollar.

operating out of compliance for any significant amount of time would result in noncompliance with the 30-day rolling average emission limit. As a result, most U.S. utility companies have chosen to have spare absorber modules rather than reduce load or shutdown when the FGD system is not operating adequately. This increases capital costs by 20% for a 500-MWe unit.

Scrubber Module Size

Many L/LS-FGD modules at the FRG plants handled 300-500 MWe equivalent of flue gas. Large module sizes reduce capital costs due to economy of scale. The size of most U.S. scrubber modules is typically 100-150 MWe to minimize spare module costs.

Sorbent and Waste Handling Quantities

All FRG coals are low in sulfur (~1%), which results in lower capital costs due to smaller sorbent and waste handling systems. By contrast, U.S. boilers have coal sulfur contents of 1 to 4%. Additionally, most of the L/LS-FGD systems in FRG receive the sorbent pulverized, and the capital cost for pulverization is reflected in the cost of the sorbent (consumables) and not in the system capital costs.

General System Design

The FRG FGD systems represent current FGD design concepts, which in general are less complex and lower in capital costs than those built in the U.S. before 1985. Process design simplification examples include single-loop scrubber with slurry addition and oxidation in the scrubber bottom, and the use of hydroclones instead of thickeners before vacuum belt dewatering. These designs represent state-of-the-art technology and are used on new U.S. systems.

Combined Systems

Another factor which affects the capital cost of FGD systems is the system size. Larger systems cost less on a $/kW basis because of economies of scale. Because the FRG regulations required almost all utility boilers to retrofit scrubbers, flue gas from adjacent boilers at the same plant were typically tied into a single large FGD system. Thus, economies of scale resulted from having a single large system, instead of multiple smaller ones, and from having larger absorber modules. For example, at the Niederaussem plant a 2700 MW system was constructed instead of having eight individual units ranging in size from 150 MW to 600 MW.

SUMMARY OF SCR RESULTS

Table 3 summarizes the capital cost comparison for SCR at four of the plants. Capital cost estimates were not possible at the lignite-fired plant in Niederaussem because it is anticipated that these boilers will meet the NO_x emission limit by retrofitting combustion modification controls. As Table 3 shows, the percent difference between the actual cost and the estimated capital cost varied between -5 to 16%. Catalyst volume and costs for the SCR systems were based on information from the plants. Access and congestion retrofit difficulty and scope adders were estimated based on procedures developed for FGD systems. The study results confirm that the major variables that affect the capital cost are the catalyst volume and cost, the retrofit difficulty, and the scope adder costs. However, still unknown is the expected catalyst life when firing U.S. coals having high sulfur, alkali metal and/or arsenic contents.

Access and congestion retrofit difficulty and general facilities were estimated using the methodology developed for FGD systems. The following access and congestion retrofit factor description was found to give close approximation to the actual reported SCR capital costs:

TABLE 3. SUMMARY OF SCR CAPITAL COST COMPARISON

Plant Name	Mannheim	Ibbenbueren	Walheim	Scholven	Scholven
Boiler/Block	7	8	2	B-E	F
Boiler type	Dry bottom	Wet bottom	Wet bottom	Dry bottom	Dry bottom
SCR type	Hot	Cold	Hot	Hot	Hot
SCR size (MWe)	475	770	153	370 each	740
NO_x removal efficiency (%)	77-82	91-92	88	67	60
Access/Congestion factor	Moderate	Base	High	Low	Moderate
Scope adder cost ($/kWe)	3.0	47.7	42.5	3.1	3.4
General facilities (%)	13	25	13	13	13
Catalyst cost					
Dollars/ft^3[a]	504	355	545	283	283
Dollars/kWe	18.7	7.4	25.2	16.2	7.8
Total capital cost ($/kWe)					
Radian estimate	82	98	180	87	57
Actual reported[b]	79	103	189[c]	75	55
Percent difference	4	-5	-5	16	3

[a] 1 m^3 = 35.3 ft^3.

[b] Costs are based on an exchange rate of DM 2 to the U.S. dollar.

[c] Excludes the costs of combustion modifications.

- Base--Similar to new plant where there is free access for large cranes and equipment near the boiler (hot side) or chimney (cold side). The Ibbenbueren plant with a cold side SCR system located behind the existing chimney is representative of this situation.

- Low--Space is somewhat limited such that a standard equipment layout is not possible, but access exists for large cranes on two sides. The Scholven units B-E with the hot side SCR reactors at ground level next to the ESPs are representative of this situation. Limited space existed between the units for locating the SCR reactors and cranes.

- Moderate--Limited space requiring special equipment designs and layouts and crane access limited to one side. The Scholven F and Mannheim 7 units represent this situation where the SCR reactors are elevated between the economizer and air heater, but outside of the boiler building. Both units are end units allowing for reasonable crane access.

- High--Severe space limitations with access for large cranes blocked on all sides. The Walheim 2 unit represents this situation where the boiler building wall was removed to allow access to construct the SCR reactors between the economizer and air heater.

CONCLUSIONS

Flue Gas Desulfurization

The results of this study show that FRG capital costs for conventional lime/limestone wet and dry FGD systems are similar when differences in the scope of supply (design) are taken into account. The major design differences found between the FRG systems and U.S. designed systems are due to the following reasons:

- Coal Sulfur Content--Higher coal sulfur content of most U.S. coals results in higher capital costs for sorbent and waste handling facilities and use of spare absorbers to ensure operating reliability.

- Combined Systems--Most FRG systems are large because of flue gas from multiple units is processed in one system. Combined systems have lower capital cost requirements due to economy of scale.

- Regulatory--NSPS bypass and averaging provisions have resulted in use of spare modules and small absorber sizes to minimize cost of spare absorbers.

- Technology Status--Most FRG systems employ 1980's technology where as most U.S. systems employ 1970's technology because of when the systems were built. Newer designs are more reliable and reduce the need for spare absorbers and allow the use of larger absorber sizes.

Based on the results of this study, it can be concluded that:

1. The lower capital cost of FGD systems in FRG relative to U.S. systems is due to scope of the supply (design) differences.

2. Future U.S. systems will have lower capital cost requirements than past systems due to technology improvements.

3. Regulatory provisions having less stringent bypass and averaging requirements than NSPS can significantly reduce the capital cost of FGD systems.

4. Combined handling of flue gas from multiple units can significantly reduce system capital costs.

Selective Catalytic Reduction

The results of this study show that FRG SCR system capital cost can be accurately estimated if catalyst cost and retrofit difficulty are known. The retrofit difficulty adjustment methodology found in the EPRI report "Retrofit FGD Cost-Estimating Guidelines" can be employed to account for different access and congestion situations found in FRG. Based on the results of this study, it can be concluded that:

1. The FRG SCR system capital costs can be used to estimate U.S. retrofit applications if adjustment for retrofit difficulty and catalyst costs are made.

2. Because of the differences in U.S. coal trace element content versus that of FRG, the catalyst life requirements of the FRG applications are not directly transferable to all U.S. applications. As such, catalyst life assumptions used to estimate annual costs must reflect this uncertainty.

The following contaminants found in utility boiler flue gases over time deactivate the catalyst: SO_x, particulate matter, arsenic, and alkali metals. The contaminants vary with the fuel and reactor location. SCR has been commercially applied in Japan and Germany to the following utility boiler situations:

Fuel Characteristics			SCR Configuration	
Fuel Type	Ash Metals	Sulfur Level	Temperature	Dust
Gas	None	None	Hot	None
Oil	Low	Low	Hot	Low
Coal	Low	1 Percent	Hot/Cold	Low/High
Coal	High Arsenic	1 Percent	Hot/Cold	Low/High

SCR has not been applied commercially on high sulfur and high alkaline coal situations. Many boilers in the U.S. burn high sulfur coals (2-5%) and coals with highly alkaline ash (lignites and subbituminous coals). Also, many of the low sulfur eastern coals have high arsenic contents. To address the lack of data available on catalyst life for hot side SCR for U.S. coals, a number of SCR pilot programs are planned.

SECTION 2

RETROFIT COST PROCEDURES

L/LS- AND LSD-FGD

This section presents the procedure used in this study to estimate the cost of retrofitting L/LS- and LSD-FGD systems at coal-fired power plants. This cost procedure was developed using the TVA Shawnee model that was incorporated into the Integrated Air Pollution Control System (IAPCS) model (5,6). To adjust the IAPCS cost and performance estimates to reflect site-specific retrofits, retrofit difficulty multipliers (retrofit factors) and scope adder costs were developed. Retrofit factors adjust cost model process area costs to reflect the cost impacts of:

- site access and congestion,
- underground obstructions, and
- distances between process areas.

Scope adder costs adjust cost model estimates by adding costs that were not addressed in the cost model algorithms. Typical scope adder costs that are not included in the cost algorithms for new plant control systems or in retrofit control system bases include:

- chimney liner or new chimney,
- demolition/relocation of existing facilities,
- additional particulate control facilities,
- conversion of wet ash handling systems to dry handling, and
- air heater modifications/replacement.

The following section describes the procedures used to develop the retrofit difficulty factors and scope adder costs. The retrofit factors, scope adder costs, and performance estimates were then input to IAPCS.

The retrofit factor methodology used for L/LS-FGD and LSD-FGD is from the EPRI report entitled "Retrofit FGD Cost-Estimating Guidelines" (1). These procedures are used to develop retrofit factors that will be applied to the IAPCS cost model.

The EPRI methodology used for the German plants is based on use of the detailed procedures that apply a series of factors to the cost of a new FGD system. The factors correct for site-specific retrofit variables. The retrofit factors are developed in this report based on the capital cost of new FGD systems as developed in the "Economic Evaluation of FGD Systems" (7).

Retrofit situations typically require equipment and/or work not necessary in a new plant FGD system. The procedures make two types of cost adjustments to new plant costs. Scope adder costs account for scope adjustments, and cost multipliers account for location and retrofit factors.

Scope adder costs or scope adjustments are additional equipment costs due to scope differences between new plant costs and a retrofit FGD system. Some of the scope adjustments considered in this study are:

- new particulate collection equipment (fabric filter);
- a new chimney, or protection of the existing chimney against the acidic effects of a wet scrubber;
- structural improvement of the boiler to provide pressure-surge protection or a draft control system to prevent surges in the fire box; and
- any demolition and/or equipment relocation necessary to make room for the new equipment.

Retrofit adjustments consider the retrofit difficulty, which is defined by the following additional site-specific criteria:

- access and congestion,
- underground obstructions,
- ductwork length and tie-in difficulty,
- distance between the scrubber and waste handling areas, and
- distance between the scrubber and sorbent preparation areas.

Access, congestion, and the ductwork distance are the major contributors to the retrofit factor. Accessibility and congestion alone can increase the capital cost of any one particular subsystem of an FGD installation by 50%.

The adjustment factors applied to the new FGD system cost yield the total process capital (TPC) costs. Additional capital costs must be calculated from the TPC to derive the total capital requirement. These costs include the following:

- engineering,
- escalation to the date of construction,
- cost of general support facilities (range from 5 to 15% of the process capital costs),
- allowance for funds during construction (AFDC),
- royalty allowances,
- preproduction cost,
- inventory capital, and
- project and process contingencies.

The summation of these costs and the TPC costs results in the total retrofit capital cost for the FGD system. The overall retrofit factors listed in this report are determined by dividing the total retrofit capital cost by the total base capital cost.

In this study, spare absorber modules were eliminated and the absorber module sizes were made consistent with the German FGD design. This was done by selecting the correct parameter file settings within the IAPCS cost model. Maximum absorber module size is in the range of 300-350 MWe.

SCR

The cost procedures for SCR were developed primarily from information provided by EPA and EPRI for new coal-fired utility boiler applications (2-4).

Instead of using the cost procedures to calculate the catalyst volume, the actual catalyst volumes obtained from the plants were used in the cost estimates. Generally, the cost procedures estimated higher catalyst volumes (roughly double) than the actual volume. Further examination of the cost procedures is required to correct the conservative catalyst volume estimates. The cost comparisons assume an exchange rate of DM 2 to the U.S. dollar for converting actual plant costs in deutsche marks to dollars.

To use these procedures for retrofit applications, access/congestion retrofit difficulty and general facilities were estimated based on procedures developed for FGD systems (6). The access/congestion factor for the SCR reactors was selected to give the lowest percent difference establishing the following selection criteria:

- Base to Low - SCR reactors at ground level with the reactors located adjacent to the air heater for hot side applications or adjacent to the chimney for cold side applications. Retrofit factors of 1.02 or 1.16 can be selected depending on access/congestion and underground obstruction.
- Moderate - SCR reactor located between the economizer and air heater where the flue gas duct coming down from the economizer is located (common configuration of large new boilers in FRG). The retrofit factor is 1.34.
- High - SCR reactor located between the economizer and the air heater but requiring economizer and extensive building modifications. The retrofit factor is 1.52.

General facilities factors of 13, 25, or 38% are selected to account for such contingencies as moving roads, parking areas, storage buildings, and labs (8). The criteria used to select the appropriate general facilities factor are:

- Base Case - Assumes one road will have to be rerouted and necessary drainage will be considered. The existing laboratory must be augmented. A warehouse structure must be built (uses 13%).
- Midrange Case - A major paved road will have to be built along with the necessary area drainage. A new laboratory, office building, and warehouse must be constructed (uses 25%).

- High Case - A major public road will have to be rerouted or built over. New laboratories, an office building, warehouse, and machine shops will be needed. The utility has purchased new land; the fence and roads for that area will need to be developed (uses 38%).

In general, this factor should be relatively low for SCR systems because they are typically smaller in size than FGD systems. Scope adder costs such as new buildings, equipment related to the retrofit, ductwork demolition, new ducting, etc., are included as additional cost items related only to the retrofit. The costs for ductwork demolition and new ducting are based on EPRI cost guidelines. The other scope adder costs were based on costs provided by the plants.

MONETARY EXCHANGE RATE

Table 4 presents the monthly closing exchange rate from 1986 to 1988 to convert U.S. dollars to German deutsche marks (9). As this table shows, the monthly closing exchange rate varied from about DM 1.6 (at the end of December 1987) to DM 2.4 (at the end of January 1986) to the U.S. dollar over the time the SCR systems were installed. The average exchange rate between 1986 and 1988 as shown in Table 4 is DM 1.9 to the U.S. dollar. The study base case assumed an exchange rate of DM 2 to the U.S. dollar (see Sections 3 and 4). Some sensitivity analyses were developed based on exchange rates of DM 1.6 and 2.4 to the U.S. dollar.

TABLE 4. FLUCTUATION OF THE MONETARY EXCHANGE RATE FROM DEUTSCHE MARKS (DM) TO U.S. DOLLARS BETWEEN 1986 AND 1988[a,b]

Month	1986	1987	1988
January	2.38	1.84	1.70
February	2.23	1.83	1.69
March	2.40	1.82	1.66
April	2.21	1.78	1.68
May	2.32	1.82	1.73
June	2.17	1.84	1.82
July	2.09	1.86	1.88
August	2.03	1.80	1.85
September	2.00	1.85	1.87
October	2.06	1.73	1.79
November	1.97	1.67	1.72
December	1.92	1.57	1.77
Yearly Average	2.15	1.78	1.76

[a]Monthly closing rate of deutsche marks to the U.S. dollar.

[b]Average exchange rate between 1986 and 1988 was DM 1.9 to the U.S. dollar.

SECTION 3

FGD

German regulations require that all coal-fired boilers >100 MWe meet a 400 mg/m^3 SO_2 emission limit and 85% reduction by July 1988. Low capacity factor boilers can operate until 1993 before retrofit or retirement. This has resulted in the application of 35,000 MWe of utility boiler FGD capacity with total FGD capacity of 45,000 MWe expected by the early 1990. All of the boilers visited at the five plants have retrofit L/LS-FGD systems currently in operation. Two of the newer boilers (Ibbenbueren and Scholven F) have FGD systems that were not difficult retrofits because 25 to 50% capacity FGD systems were installed when the units were constructed. Mannheim Unit 7 was also an easy retrofit because space behind the chimney was left open in the event that a 50% capacity combined NO_x/SO_2 FGD process under development was not successful.

This section presents the actual FGD capital costs obtained from the four German power plants and compares the actual FGD capital costs with those estimated from the U.S. procedures (IAPCS model). The cost comparison was conducted to identify capital cost differences and the reasons for the differences, and to identify changes to the cost estimating procedures.

The FGD description and cost comparison for Walheim, Mannheim, Ibbenbueren, and Niederaussem plants, respectively, follows.

WALHEIM PLANT

FGD Description

The Walheim Block 1 and 2 boilers have retrofit LSD-FGD units that were operational in 1987. The boilers have a combined lime receiving and storage system and waste handling system. The boilers have separate flue gas ducting arrangements that include fans, spray dryer modules housed in the same building, pulse jet fabric filters, and steam reheat systems. Flue gas

passes through the existing electrostatic precipitator (ESP) and induced draft (ID) fan, enters the spray dryer vessel at 130 °C, and leaves at 65 °C. The flue gas enters the fabric filter and then is reheated to 75-80 °C to meet the regulatory discharge temperature of 72 °C. The SO_2 removal efficiency is 90% on a coal having a 0.7 to 1.3% sulfur content. The LSD waste is blended with 50% of the boiler fly ash and is loaded onto ships that take the material to a landfill site in Belgium. The lime and waste handling systems have ship and truck loading/unloading systems, although lime/waste are currently handled only by ship. Flue gas ducting is provided to bypass the fabric filter in the event that the spray dryer shuts down (preventing heat damage to fabric filter bags).

Because there is sufficient space between the ESPs and the common chimney, a low site access congestion factor is assigned to the LSD absorber and fabric filter locations. It is estimated that about 300 feet (91 m) of duct length were required to bring the flue gas from ESPs to absorbers, fabric filters, and the existing chimney.

Costs

The actual capital cost for a new FGD system is DM 82 million or $41 million. The following items are included in the capital costs:

	DM 10^6 ($\$10^6$)
Foundation	13 (6.5)
Controls/electrical	8 (4)
Spare parts	3 (1.5)

Retrofit factors resulted in a DM 3 to 4 million increase in cost over a new plant. Total retrofit capital cost is about DM 86 million. On a kilowatt basis, total actual retrofit capital cost is $170/kW.

Table 5 presents the estimated retrofit costs for the LSD-FGD system and new fabric filters. The costs were estimated by IAPCS based on the inputs shown in this table. The estimated capital cost is $190/kW. The difference from the actual capital cost is 12%.

TABLE 5. SUMMARY OF RETROFIT FACTORS AND CAPITAL COST DATA FOR WALHEIM

Parameter	LSD-FGD with new fabric filters Blocks 1 and 2
Site access/congestion	
SO_2 removal	Low
Flue gas handling	Low
New fabric filter	Low
Ductwork distance (meters)	91
Scope adjustment costs ($1000)	
Wet to dry ash handling system	0
Draft control costs	340
Retrofit factors	
FGD system	1.16
New fabric filter	1.10
General facilities	10
Estimated total capital cost ($/kW)	190
Actual total capital cost ($/kW)	170
Percent difference	12

The difference between actual and estimated capital costs assumes that the exchange rate is DM 2 to the dollar. If the exchange rate is DM 2.4 to the dollar, which corresponds to the highest exchange rate between 1986 and 1988, the difference is 34%. At this exchange rate, the actual capital cost is $142/kW. If the exchange rate is DM 1.6 to the dollar, which corresponds to the lowest exchange rate between 1986 and 1988, the difference is -11%. At this exchange rate, the actual capital cost is $213/kW.

MANNHEIM PLANT

FGD Description

The Mannheim Block 7 boiler limestone FGD (LS-FGD) system began operating in July/August 1988. The Block 3 and 4 boiler LS-FGD system was started up in August 1988. Both FGD systems use a single absorber with a prescrubber before the main spray tower. High quality pulverized limestone is delivered to the plant by rail. The prescrubbers remove chlorides and ash to ensure good quality gypsum. The Block 7 waste handling system consists of very dry 95% pure gypsum product that is exported to Scandinavia. The Block 3 and 4 waste handling system consists only of a belt filter that reduces gypsum moisture to less than 10%. A special gypsum silo was designed and built to ensure easy handling of the moist gypsum. Gypsum is transported from the plant by rail and barge. Ash and chloride levels to the absorber must be less than 75 mg/m^3 and 100 mg/m^3, respectively.

Typical materials of construction for wet FGD system used were:

- coated wet ducting,
- rubber-lined pumps and wetted surfaces (lower absorber section),
- stainless steel and carbide nozzles, and
- stainless steel upper absorber sections.

The design and actual liquid-to-gas ratio are 12 and 10 L/m^3, respectively.

The tie-in of Blocks 3 and 4 required 6 weeks, also scheduled during the annual maintenance outage. Installation of the SCR and FGD systems requires the replacement of the ID fans that extended the tie-in and construction time.

The Block 7 FGD system required 5 weeks downtime for tie-in, which was scheduled during the annual maintenance outage. The retrofit difficulty of the Block 7 FGD system was low. This FGD system was located immediately behind the existing chimney (short flue gas duct runs) in an area having low access/congestion difficulty. The retrofit difficulty of the FGD systems for Blocks 3 and 4 was very high due to the extremely limited access and

extreme congestion. The FGD and SCR systems for these boilers were built up over existing buildings because the boilers were built beside the river. The limestone/waste storage silos were stacked on top of each other and built over the road and railroad track running along the river bank. By examining the aerial photographs taken prior to the FGD installation, it was obvious that two storage buildings behind the Unit 7 chimney FGD system were relocated to provide more space for FGD units. As such, 8% was assigned to the general facilities.

Costs

Reported capital costs for Blocks 3 and 4 include the cost for the combined FGD and SCR systems. The actual capital cost of FGD for Blocks 3 and 4 was roughly estimated at DM 125 million or $62.5 million. The cost split between the FGD and SCR options is difficult to determine because both were built at the same time. This cost estimate assumes a 50-50 split in capital costs. Because of the inaccuracy in the split between the FGD and SCR costs, a capital cost comparison was not performed in this study for the Unit 3 and 4 FGD system.

The actual capital cost of the Block 7 FGD system is DM 135 million ($67.5 million), which includes: DM 12 to 13 million for reheating flue gas to the flue gas exchanger and DM 13 million for wastewater treatment facilities. On a kilowatt basis, the total capital cost is $140/kW.

Table 6 presents the estimated retrofit costs for the LS-FGD system for Unit 7. The costs were estimated by IAPCS based on the inputs shown on this table. The estimated capital cost is the same as the actual cost; therefore, the difference in capital costs is zero.

This difference in capital cost assumes that the exchange rate is DM 2 to one U.S. dollar. If the exchange rate is DM 2.4 to the dollar, the difference is 20%. At this exchange rate, the actual capital cost is $117/kW. If the exchange rate is DM 1.6 to the dollar, the difference is -20%. At this exchange rate, the actual capital cost is $175/kW.

TABLE 6. SUMMARY OF RETROFIT FACTOR AND CAPITAL COST DATA FOR MANNHEIM BLOCK 7

Parameter	LS-FGD
Site access/congestion	
SO_2 removal	Low
Flue gas handling	Low
Ductwork distance (meters)	30
Scope adjustment costs ($1000)	0
Retrofit factor	
FGD system	1.10
General facilities	8
Estimated total capital cost ($/kW)	140
Actual total capital cost ($/kW)	140
Percent difference	0

IBBENBUEREN PLANT

FGD Description

The Ibbenbueren plant has only one operating boiler, Block B. This boiler started operation in 1985 with a lime FGD system located in front of the chimney, scrubbing 50% of the flue gas. In 1986, a second scrubbing module was added and, in 1987, a third module came on-line. The phased approach was in response to rapidly changing local/federal regulations influencing the degree of scrubbing required. However, because the boiler

was initially constructed to have space for an FGD system rated for 100% boiler capacity, the addition of more scrubbing modules was not difficult. Flue gas reheat is provided by two flue gas-to-flue gas heat exchangers.

The FGD system uses calcium hydroxide [$Ca(OH)_2$] to meet the gypsum quality specification. A double-loop slurry scrubbing system is used, and the gypsum slurry passes through a thickener to a centrifuge where the gypsum is dewatered to greater than 90% gypsum. The gypsum is given away at no cost to a wallboard manufacturer. Three 250-MW modules were assumed in the IAPCS model. A low site access/congestion factor with low underground obstructions and general facilities (5%) was assumed for the absorber locations. The duct length requirement was estimated to be about 100 feet (30 m) with a low site access/congestion factor assigned to flue gas handling system.

Costs

The actual capital cost of the FGD system is DM 200 million or $100 million. On a kilowatt basis, the total capital cost is $130/kW. Table 7 presents the estimated capital costs for the lime-FGD system. The costs were estimated by IAPCS based on the inputs shown in this table. The estimated capital cost is $119/kW. The difference between capital cost and actual is -8%.

This difference in capital cost assumes that the exchange rate is DM 2 to the dollar. If the exchange rate is DM 2.4 to the dollar, the difference is 10% and the actual capital cost is $108/kW. If the exchange rate is DM 1.6 to the dollar, the difference in capital costs is -27% and the actual capital cost is $163/kW.

TABLE 7. SUMMARY OF RETROFIT FACTOR AND CAPITAL COST DATA FOR IBBENBUEREN

Parameter	Lime-FGD
Site access/congestion	
SO_2 removal	Low
Flue gas handling	Low
Ductwork distance (meters)	30
Scope adjustment costs ($1000)	0
Retrofit factor	
FGD system	1.10
General facilities	5
Estimated total capital cost ($/kW)	119
Actual total capital cost ($/kW)	130
Percent difference	-8

NIEDERAUSSEM PLANT

FGD Description

The Niederaussem plant is a brown (lignite) coal-fired plant having two 150-MWe, four 300-MWe and two 600-MWe boilers. The plant fires a coal with a sulfur content range of 0.1 to >1.4%, a moisture content of 50 to 65%, an ash content of 2 to 20%, and a heating value of <4000 Btu/lb (9.3 Mj/kg). Boilers are sitting side by side with old chimneys and 11 cooling towers

placed behind them. Because the boiler cooling towers were located behind the existing chimneys, the LS-FGD systems had to be located behind the cooling towers. This resulted in very long flue gas duct runs. Although the access/congestion difficulty was low, the very long flue gas duct runs resulted in a very high cost system. A single building houses the FGD absorbers, each scrubbing the equivalent of approximately 300 MWe of flue gas (nine flue gas trains).

Absorbers are located behind the cooling towers in an area with little or no site access/congestion or underground obstruction similar to a new plant. However, the location is away from the boiler house. To estimate the duct length requirement, the distance between each unit and the absorbers was estimated. This is a combined FGD system and, as such, a duct-length requirement was estimated by weight averaging (based on boiler size) the duct length. The duct length varied from 1700 to 2600 feet (518-792 m) with the weighted average being 2100 feet (640 m). Because of the congestion created by the cooling towers and underground obstructions created by the circulating water pipes, high site access/congestion and underground obstruction values were assigned to the flue gas handling system. In addition, two new chimneys were constructed behind the absorbers; these were added to the capital costs as scope adder costs.

Pulverized limestone is shipped in by train, and the gypsum waste product is disposed of at the mine after being dewatered by belt filters. The scrubbed flue gas is ducted back to the cooling towers for seven of the flue gas trains and to a new chimney for the other two flue gas trains (the first four boilers have forced draft cooling towers). The flue gas ducted to the natural draft cooling towers achieves sufficient increase in temperature and plume rise to satisfy the FRG regulations for flue gas exit temperature (72 ^{o}C).

The boiler flue gas contains 25 mg/m^{3} of chlorides. The chlorides leave the scrubber system only with the water contained in the gypsum (10-20% of gypsum by weight) and the 15% by weight used to wet the fly ash. Chloride levels in the scrubber slurry system are 12 to 20 mg/L. Because of the high chloride levels, the gypsum dewaters easily and air oxidation is no longer employed.

Costs

Because this plant was visited by the NATO Committee on the Challenges of the Modern Society working group, detailed costs for the FGD system were not available. The overall capital cost of the 2700 MWe of LS-FGD system was reported DM 1.3 billion or $650 million. The capital costs include the following major systems: 14 separate flue gas duct runs to the absorbers; 7 separate flue gas duct runs to the natural draft cooling towers; chimney and ducting for boilers A-C; bypass chimney and ducting for boilers D-H; combined limestone handling system (does not include pulverizer costs); combined gypsum dewatering system (2 vacuum belt filters with space available for a third); absorber building; and buildings for manufacturing the large diameter (7-9 m) flue gas ducting. The FGD systems were provided by Steinmueller and General Electric Environmental Systems.

The capital costs of $240/kW for the Niederaussem plant is much higher than for a typical 2700 MWe new plant FGD system because of the very long flue gas duct runs and the high flue gas volume per megawatt of power generated (low heating value or the coal). Also, the design SO_2 concentration is based on 1.4% sulfur in the coal. As such, each absorber has five scrubber slurry pumps with only one or two operating normally.

Table 8 presents the estimated capital cost for the combined LS-FGD system. The cost was estimated by IAPCS based on the inputs shown in this table. The estimated capital cost is $260/kW, resulting in a difference from the actual cost of 8%.

The difference in capital cost assumes that the exchange rate is DM 2 to the dollar. If the exchange rate is DM 2.4 to the dollar, the difference is 16%. At this exchange rate, the actual capital cost is $208/kW. If the exchange rate is DM 1.6 to the dollar, the difference in capital cost is -23%. At this exchange rate, the actual capital cost is $313/kW.

TABLE 8. SUMMARY OF RETROFIT FACTOR AND CAPITAL COST DATA FOR NIEDERAUSSEM

Parameter	LS-FGD units A-H
Site access/congestion	
SO_2 removal	Low
Flue gas handling	High
Ductwork distance (meters)	91
Scope adjustment costs ($1000)	
Chimneys (2)	12,420
Retrofit factor	
FGD system	1.87
General facilities	5
Estimated total capital cost ($/kW)	260
Actual total capital cost ($/kW)	240
Percent difference	8

CONCLUSIONS

Based on this evaluation of the reported FGD capital costs for systems recently retrofit in the Federal Republic of Germany, the following conclusions seem appropriate:

1. The retrofit FGD cost estimating procedures documented in EPRI report CS-3696 (1) were used to accurately estimate the retrofit difficulty of the German systems. The IAPCS cost model was used to calculate capital costs after inputting the EPRI procedure-

derived retrofit difficulty factor. The close agreement between the estimates and the FRG actual costs confirms the accuracy of the methodology and cost model.

2. German systems have significantly lower capital costs versus U.S. systems because of economies of scale (larger absorber sizes) and elimination of spare scrubber modules.

3. The higher sulfur content of most eastern U.S. coals increases the cost of FGD systems in the United States versus FRG due to the increased SO_2 removal requirements (higher liquid-to-gas transfer ratio), the increased sorbent and waste handling requirements, and the increased operating difficulties associated with high sulfur coals.

The FRG has benefitted from technology improvements developed since most U.S. systems have been built. Use of organic acids (Saarberg-Holter process), hydroclones and simpler system designs are examples. The reduction in costs due to the use of hydroclones and simpler system designs was not observed; otherwise the IAPCS cost estimates would be consistently higher than the FRG actual costs. These modest cost reductions were not observed because of the large reduction in costs associated with economies of scale when building a very large system such as Niederaussem (2700 MW) and large absorber modules (>300 MW), and when eliminating spare modules.

SECTION 4

SCR

German regulations were adopted in 1986 that set emission limits for NO_x from coal-fired boilers greater than ~100 MWe to less than 200 mg/m^3. Therefore, new and existing coal-fired boilers of greater than 100 MWe have a new retrofitting SCR with compliance required by 1989-1990.

Four of the five plants visited (Walheim, Mannheim, Ibbenbueren, and Scholven) have boilers that are operating or have under construction SCR controls. The Niederaussem plant is lignite fired and applies combustion modification controls to comply with the 200 mg/m^3 emission limit.

This section presents the actual SCR capital costs obtained from the four German power plants and compares the actual capital costs with those estimated for the U.S. SCR cost procedures. The cost comparison was conducted to identify capital cost differences, the reasons for the differences, and to identify changes to the cost estimating procedures.

The SCR description and cost comparison for the Walheim, Mannheim, Ibbenbueren, and Scholven plants, respectively, follows.

WALHEIM PLANT

SCR Description

The Walheim plant has two coal-fired boilers of 103 MWe (Boiler 1) and 153 MWe (Block 2). SCR has been applied to Block 2. Table 9 summarizes the design/operating data on the Block 2 SCR system. This high-dust SCR system was installed in 1986-1987. Additional equipment related to the retrofit includes a new air heater, ESP reinforcement, fly ash recycle system modification, economizer modification for temperature control, and additional foundation. Because the SCR reactor is located between the economizer and the air heater and because the retrofit required extensive

TABLE 9. WALHEIM BLOCK 2 SCR DATA SUMMARY

Parameter	Block
Boiler size (MWe)	153
Bottom ash type	Slag
Capacity factor (%)	
Current	57
Future	25
Coal properties	
Heating value (Mj/kg)	28
Sulfur (%)	0.7-1.3
SCR system	
Type	High dust
Catalyst manufacturer	BASF
Catalyst volume (m^3)	200
Catalyst layers	3 plus 1 future
Ammonia slip (design ppm)	5
NO_x reduction (%)	88
NO_x concentration (mg/m^3)	
Inlet	1700 (after combustion controls)
Outlet	200

economizer modifications, a high access and congestion retrofit difficulty factor is assessed. The general facilities factor was low for this boiler because none of the roads and buildings surrounding the retrofit area had to be relocated.

The SCR unit has been on-line since 1987 and has had difficulty achieving the 90% NO_x reduction because of the high NO_x inlet concentration and the high arsenic concentration in the hot flue gas. German coals typically have a 3-5 mg/kg arsenic concentration, and most wet bottom boilers recycle the fly ash back to the boiler to eliminate the need for fly ash disposal. However, arsenic condenses on the fly ash and is recycled, resulting in high arsenic levels in the flue gas (1000 mg/m^3). Arsenic is a catalyst poison for vanadium-based SCR catalysts. To achieve the 200 mg/m^3 emission limit for NO_x without limiting the type of coal burned (fuel nitrogen level), the boiler has been retrofitted with low NO_x combustion techniques (over-fire air). This has reduced NO_x inlet levels to 1700 mg/m^3. Additionally, only 50% of the fly ash is now recycled, significantly reducing the arsenic content of the flue gas. Now that these modifications have been made, the SCR system is currently achieving about 90% NO_x removal.

Costs

Table 10 presents the actual capital costs of the NO_x control system for Walheim Block 2, obtained from the site visit. Total capital costs were DM 65.2 million or $32.6 million. Costs related to retrofit that would not be included for a new unit are DM 13 million or $6.5 million. Excluding the cost for combustion modification, the unit capital cost is $189/kW.

For comparison, unit capital cost based on the U.S. cost procedure is estimated at $180/kW. The difference from the actual capital costs of $189/kW is -5%. The U.S. estimated cost is based on a high retrofit difficulty factor (1.52), a low general facilities factor (13% process capital costs), and a scope adder cost of $6.5 million. A catalyst volume of 200 m^3 (7060 ft^3) at a cost of DM 38,500/m^3 (to $545/$ft^3$) was used in the cost procedures, based on data presented in Tables 9 and 10.

The percent difference in capital cost of -5% assumes that the exchange rate is DM 2 to the U.S. dollar. If the exchange rate is DM 2.4 to the U.S. dollar, which corresponds to the highest exchange rate between 1986 and 1988, the percent difference is 14%. At this exchange rate, the actual capital cost is $158/kW. If the exchange rate is DM 1.6 to the dollar, which corresponds

TABLE 10. NO_x CONTROL CAPITAL COSTS FOR WALHEIM BLOCK 2

Cost items	Capital costs DM 10^6 ($\$10^6$)[a]
SCR components	
Controls	7.0 (3.5)
Ammonia storage	1.0 (0.5)
Foundations	2.5 (1.3)
Reactor/mechanics	26.5 (13.2)
Catalyst	7.7 (3.8)
Combustion modifications	7.5 (3.8)
Other modifications associated with retrofit	
New air heaters (2)	6.4 (3.2)
ESP reinforcement	1.0 (0.5)
Economizer modifications	3.0 (1.5)
Fly ash system	0.5 (0.3)
Foundations	2.1 (1.0)
Total capital costs	65.2 (32.6)
Total capital costs per kW	378 (189)[b]

[a]Costs are based on an exchange rate of DM 2 to the U.S. dollar.
[b]Number in parentheses excludes the costs for combustion modifications.

to the lowest exchange rate between 1986 and 1988, the percent difference is -24%. At this exchange rate, the actual capital cost is $236/kW.

MANNHEIM PLANT

SCR Description

The Mannheim plant has three operating coal-fired boilers generating district heating and electricity. Table 11 summarizes the design and operating data obtained on these boilers. Blocks 3 and 4 are in the process of being retrofitted with a combined LS-FGD system and a tail-gas SCR system. Because very little space was available behind these units, the retrofit difficulty for these units was high. Additionally, the FGD/SCR system construction occurred during normal unit operation and system tie-in time was minimized. SCR-system construction for Blocks 3 and 4 is over 90% complete with the start-up expected by the end of 1988. The SCR-system is designed to achieve approximately 90% NO_x removal.

For Block 7, a new unit, there is space behind the chimney to easily retrofit the lime FGD system. Although the SCR system had to be built over the air heaters, access to the flue gas ducting between the economizer and air heater was easy. Flue gas is ducted outside the boiler building to the air heaters. This is typical of newer unit designs where the boiler economizer is stacked on top of the furnace. (Newer units are designed in Germany to be cyclic units. Stacking the boiler economizer on top of the furnace helps to minimize the thermal stresses and shock during cyclic operation.) The SCR catalyst section is located where the flue gas duct comes down. Despite this simplified design, access was restricted during the construction of the unit. A moderate access and congestion retrofit difficulty factor was assessed. The general facilities factor was low for Block 7 because none of the roads and buildings surrounding the retrofit area had to be relocated. Block 7 SCR systems started up in July 1988 and have successfully operated since start-up, achieving NO_x removals between 77 and 82%.

TABLE 11. MANNHEIM SCR DATA SUMMARY

Parameter	Blocks 3 & 4	Block 7
Boiler size (MWe)	220 each	475
Bottom ash type	Slag	Dry
Capacity factor (%)		
Current	60	90
Future	50	90
Coal properties		
Heating value (Mj/kg)	28	28
Sulfur (%)	0.8	0.8
Ash (%)	4-5	4-5
SCR system		
Type	Tail-end	High dust
Catalyst manufacturer	NA[a]	NA
Catalyst volume (m^3)	360	500
Catalyst layers	2 plus one reserve	3 plus 1 reserve
Ammonia slip (design ppm)	NA	5
NO_x reduction (%)	88	77-82
NO_x concentration (mg/m^3)		
Inlet	1650	650-850
Outlet	<200	150

[a]NA = not available.

Costs

Because actual costs for Blocks 3 and 4 include the costs for the SCR and FGD and could not be accurately estimated, cost estimates for Blocks 3 and 4 were not developed. The actual SCR capital cost for Block 7 is DM 75 million or $37.5 million. Of the total SCR capital cost, the catalyst costs were DM 17.8 million ($8.9 million); on a volume basis, the catalyst cost is DM 35,600/m^3 ($504/$ft^3$). The total SCR capital cost for Block 7 on a kilowatt basis is $79/kW.

For comparison, unit capital cost based on the U.S. cost procedures is $82/kW. The difference from the actual costs is 4%. The U.S. estimated cost is based on a moderate retrofit difficulty factor (1.34), a low general facilities factor (13% of the process capital cost), and a scope adder cost of $1,410,000 for ductwork demolition and 100 feet (30 m) of new ducting. Catalyst volume of 500 m^3 (17,660 ft^3) at a cost of DM 35,600/m^3 ($504/$ft^3$) was used in the cost procedures.

The percent difference in capital cost of 4% assumes that the exchange rate is DM 2 to the dollar. If the exchange rate is DM 2.4 to the dollar, the percent difference is 24%. At this exchange rate, the actual capital cost is $66/kW. If the exchange rate is DM 1.6 to the dollar, the percent difference is -17%. At this exchange rate, the actual capital cost is $99/kW.

IBBENBUEREN PLANT

SCR Description

The Ibbenbueren plant has only one operating unit, Block B. Table 12 summarizes the design/operating data for the Block B SCR system. Boiler operation was started without an SCR system, which was in the final stages of construction with start-up planned by the end of 1988. A tail-end SCR was selected and space was available behind the chimney, making the retrofit easy. Therefore, a low access and congestion retrofit difficulty factor was assessed. However, the general facilities factor was moderate since the total gas SCR system will require more relocation/demolition of existing

equipment, buildings, and possibly roads than would a hot side (high dust) SCR system. Because the SCR system is a tail-end unit, a flue gas-to-flue gas preheater followed by a steam reheater has been installed to boost the flue gas temperature to 320 °C (608 °F).

TABLE 12. IBBENBUEREN SCR DATA SUMMARY

Parameter	Block B
Boiler size (MWe)	770
Bottom ash type	Slag
Capacity factor (%)	50-60
Coal properties	
Heating value (Mj/kg)	29
Sulfur (%)	0.9-1.1
Ash (%)	7-9
Arsenic (mg/kg)	3-5
SCR system	
Type	Tail-end
Catalyst manufacturer	KWU-BASF
Ammonia slip (design ppm)	<5
NO_x reduction (%)	91-92
Catalyst volume (m^3)	455
NO_x concentration (mg/m^3)	
Inlet (full/half)	2200-2400/1300-1000
Outlet (full/half)	<200

Costs

Table 13 presents the actual capital costs of the tail-end SCR system for Ibbenbueren, Block B. Total capital costs were DM 158.8 million or $79.4 million. Of the total SCR capital costs, the catalyst costs DM 11.4 million ($5.7 million). On a volume basis, the cost of the catalyst is DM 25,100/m^3 ($355/$ft^3$). The unit SCR capital cost is $103/kW.

For comparison, unit capital cost based on the U.S. cost procedures is estimated at $98/kW, which is about 5% less than the actual reported cost. The U.S. estimated cost is based on a base retrofit difficulty factor (1.02), a moderate general facilities factor (25% of the process capital costs), and a scope adder cost of $36.7 million. The scope adder cost includes the cost provided by the plant ($34.1 million) for a new air heater, steam heater, and buildings as well as the estimated cost ($2.6 million) for ductwork demolition and 150 feet (46 m) of new ducting.

TABLE 13. TAIL GAS SCR CAPITAL COSTS FOR IBBENBUEREN

Cost items	Capital costs DM 10^6 ($$10^6$)[a]
SCR components	78.5 (39.3)
Catalyst	11.4 (5.7)
Auxiliary materials/supplies	13.4 (6.7)
Field labor, general facilities, construction expenses	13.7 (6.8)
Building/Site development	41.8 (20.9)
Total capital costs	158.8 (79.4)
Total capital costs per kW	206 (103)

[a]Costs are based on an exchange rate of DM 2 to the U.S. dollar.

The above U.S. estimated cost assumes that the exchange rate is DM 2 to the dollar. If the exchange rate is DM 2.4 to the dollar, the percent difference between actual and U.S. estimated capital costs would be 14%. At this exchange rate, the actual capital cost is $86/kW. If the exchange rate is DM 1.6 to the dollar, the percent difference is -24%. At this exchange rate, the actual capital cost is $129/kW.

SCHOLVEN PLANT

SCR Description

This plant has five coal-fired boilers and two oil-fired boilers. Table 14 summarizes design and operating data obtained on the six boilers. SCR retrofits have been completed on the two oil-fired boilers, and work is ongoing to retrofit the coal-fired boilers with high-dust SCR systems. The retrofit difficulty is relatively low for the four 370-MWe Block B-E boilers because the SCR systems are located on the ground in a relatively open area. The Block F-H boiler SCR retrofits are somewhat more difficult (moderate) because of the large unit size (714-740 MWe) and the exposed flue gas duct that comes down, which is typical of newer German boilers as discussed for the Mannheim plant. General facilities factors for the SCR systems at the Scholven plan are considered to be low because none of the roads and building surroundings for retrofit areas had to be relocated.

SCR systems for Blocks B-E are currently under construction. The SCR systems for Blocks F-H were started up between 1986 and 1987. Catalyst pitch for the oil units is 4 mm and for the coal units is 9 mm. The SCR systems for Blocks B-E are designed for 67% NO_x removal. The plant reported that more catalyst was added to the SCR reactors for Blocks B-E for operation at lower temperature than optimal. For Block F, the SCR system is designed for 60% NO_x removal although 80% NO_x removal is expected for the SCR systems on Blocks G-H. Catalyst volume information was not provided for Blocks F-H.

TABLE 14. SCHOLVEN PLANT SCR DATA SUMMARY

Parameters	Boilers B-E	Boilers F	Boilers G-H
Boiler size (MWe)	370	740	714
Bottom ash type	Dry	Dry	NA
Fuel properties	Ballast coal	Hard coal	Distillate oil
Heating value (MJ/kg)	23	28	NA
Sulfur (%)	1.3	<1	NA
Ash (%)	25	~25	NA
SCR system			
Type	High dust	High dust	High dust
Catalyst manufacturer	Siemen	IH	Babcock
Catalyst volume (m^3)	~600	NA	NA
Catalyst layers	NA[a]	3	2
Ammonia slip (design ppm)	1-2	1-2	1-2
NO_x reduction (%)	67	60	80
NO_x concentration (mg/m^3)			
Inlet	600	<500	700
Outlet	<200	<200	<150

[a]NA = not available.

Costs

The actual capital cost of each SCR system for Blocks B-E is DM 150/kW or $75/kW. For Block F, the actual SCR capital cost is DM 110/kW ($55/kW), and for Blocks G-H the actual SCR capital cost is DM 41/kW ($21/kW). The costs include catalyst cost.

For comparison, unit SCR capital cost for Blocks B-E based on the U.S. cost procedures is estimated at $87/kW. The difference in capital cost from the actual cost is 5%. The U.S. estimated cost is based on a base retrofit factor (1.16), a low general facilities factor (percent), and a scope adder cost of $1,140,000 for ductwork demolition and 100 feet (30 m) of new ducting. Catalyst cost was assumed to be DM 20,000/m^3 ($283/$ft^3$) because the SCR system is relatively new and the present cost of catalyst has dropped dramatically in the past 2 years (10).

For Block F, unit SCR capital cost estimated by the U.S. procedure is $57/kW. The percent difference in capital cost is 3%. The U.S. estimated cost is based on a moderate retrofit factor (1.34), a low general facilities factor (13%), and a scope adder cost of $2,520,000 for ductwork demolition and 150 feet (46 m) of new ducting. Catalyst cost was assumed to be DM 20,000/m^3 ($283/$ft^3$). Catalyst volume for Block F was not available from the plant. Catalyst volume of 580 m^3 (20,472 ft^3) was determined by first estimating the space velocity of 4,567/hr using the following equation:

$$\frac{SV_1}{SV_2} = \frac{\ln (1-N_2)}{\ln (1-N_1)}$$

where SV = space velocity in hr^{-1}

N = NO_x removal efficiency, fraction.

ln = natural log

Subscript 1 = Block F SCR

Subscript 2 = Base plant data

The data presented above for Mannheim Block 7 were used in the preceding equation for the base plant, where SV_2 = 2600 hr^{-1} and N_2 = 0.8. From the space velocity, the catalyst volume is estimated by dividing the flue gas flowrate by the space velocity.

No costs were estimated using the U.S. procedures for the SCR systems at Blocks G-H because the catalyst volume information was not available.

The above U.S. estimated costs for the SCR systems of Blocks B-F assume that the exchange rate is DM 2 to the dollar. For Blocks B-E, if the exchange rate varies from DM 1.6 to 2.4 to the dollar, the percent difference in the actual cost varies from -7 to 38%, respectively. For Boiler F, the percent difference varies from -17 to 24%.

CONCLUSIONS

Table 3 summarizes the capital cost comparison for SCR at four plants. The difference between the actual cost and the estimated capital cost varied from -5 to 16%. The percent difference is relatively small. The cost procedures are based on retrofit difficulty and general facilities described for FGD systems.

For this study, the catalyst cost on a volumetric basis was found to be relatively insensitive to the total SCR capital costs within the range of catalyst cost examined in this report. As an example, the decrease in the total SCR capital cost for Mannheim Block 7 is only 11% when the catalyst cost is decreased 44%, from \$504/ft^3 (DM 35,600/m^3) to \$283/ft^3 (DM 20,000/m^3).

Under a recent study funded by EPRI, cost estimates for a retrofit of SCR on oil- and coal-fired utility boilers were developed based on FRG experience. Table 15 compares the results of this study (11).

The EPRI study case would be classified as a moderately difficult situation (SCR reactors over the air heater) relative to the FRG situations evaluated here. The cost results compare well to the Scholven B-E and Mannheim 7 boilers that are of the same size range and retrofit difficulty. Although, there are differences in the catalyst costs and volume, these differences are not great enough to change the conclusion that the EPRI-estimated costs compare well to the FRG actual costs.

TABLE 15. SCR COST COMPARISON OF A U.S. ESTIMATE TO SCHOLVEN B-E AND MANNHEIM 7 BOILERS

Design/Cost parameter	Scholven B-E actual	Mannheim 7 actual	EPRI estimate[12]
Boiler size (MWe)	370	475	400
Inlet NO_x emissions ($lbs/10^6$ x Btu)[a]	1.1	0.6	0.6
NO_x removal (%)	67	77-82	80
Retrofit difficulty	Low	Medium	Medium
Catalyst volume (ft^3)	21,190	17,660	18,500
Catalyst cost ($/$ft^3$)[b]	283	504	330
Capital cost ($/kW)	75	79	78

[a] 1 lb/Btu = 431 kg/MJ.
[b] 1 m^3 = 34.3 ft^3.

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